BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC 77

In the Matter of PACIFICORP dba PACIFIC POWER, 2021 Integrated Resource Plan.	Initial Comments of Renewable Northwest **December 3, 2021**

I. INTRODUCTION

Renewable Northwest is grateful to the Oregon Public Utility Commission ("the Commission" or "PUC") for the opportunity to comment on the 2021 Integrated Resource Plan ("IRP") filed by PacifiCorp on September 1, 2021. Overall, Renewable Northwest appreciates PacifiCorp's robust and inclusive stakeholder process, its commitment to using modern and granular analytical tools to model their portfolios and evaluate the economic potential in pairing coal retirements with renewable resource additions, and its resulting preferred portfolio, which reflects that economic potential.

In these comments, we begin by discussing the background that informed the IRP's development, including the Commission's acknowledgment of PacifiCorp's 2019 IRP, PacifiCorp's initial coal-study commitment and the process that followed, and the interplay between PacifiCorp's 2019 IRP and the resulting procurement process. We then provide our comments on this IRP: First, we offer general support with caveats for the 2021 IRP as an important step toward a more modern grid that relies on renewable, hybrid, and energy storage resources. We also share concerns regarding the company's proposed coal-to-gas conversions and market-purchase limitations. Second, we offer general support for PacifiCorp's approach to portfolio modeling using PLEXOS while also encouraging further study in future IRP cycles to facilitate additional economic coal retirements. And third, we offer general support for PacifiCorp's action plan, noting that the wind and solar-plus-storage additions in the preferred portfolio are warranted by historically low costs and value streams but also share concerns related to the inclusion of coal to gas conversion and the Natrium nuclear power plant.

Before moving into our detailed comments, Renewable Northwest reiterates our appreciation for PacifiCorp's inclusive process but also highlights the need in future planning cycles to ensure careful alignment of least-cost, least-risk resource planning with the deeply important Oregon policy goal of reducing greenhouse gas emissions as required by House Bill 2021. Under the law, retail electricity providers shall reduce greenhouse gas emissions by 80 percent below baseline emissions levels by 2030, by 90 percent below baseline emissions level by 2035, and by 100 percent below baseline emissions levels by 2040. While this IRP continues PacifiCorp's recent work to pursue economic resources that facilitate decarbonization, additional work will be necessary to accelerate the company's transition at the rate required by Oregon law. Renewable Northwest looks forward to working with the Commission, the company, and other stakeholders to achieve this crucial outcome.

Finally, Renewable Northwest notes the possibility of federal legislation in the near future that could significantly affect resource economics and utility decisions. While we do not address that possibility in these comments, we may look to do so in future filings.

II. BACKGROUND

1. Resource Planning

Under ORS 756.040(2), the Commission has the broad "power and jurisdiction to supervise and regulate every public utility and telecommunications utility in this state, and to do all things necessary and convenient in the exercise of such power and jurisdiction." Exercising that authority, the Commission has promulgated OAR 860-027-0400, which requires each investor-owned utility to file an IRP "detailing its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives to meet those needs, and its action plan to select the best portfolio of resources to meet those needs … within two years of its previous IRP acknowledgement."

In addition to its IRP rules, the Commission in Order 07-047 adopted IRP guidelines setting as the primary goal of the IRP to "select[] a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[1] The guidelines also direct the utility to address risk by, at a minimum, considering cost risk and the risks associated with physical and financial hedging.[2] Finally, the guidelines direct the utility to put forward an IRP that is "consistent with the long-run public interest as expressed in Oregon and federal energy policies."[3] Subsequent Commission Order 12-013 establishes an additional

[1] Oregon Public Utility Commission, Docket No. UM 1056, Order No. 07-047, Appendix A at 1-2 (Feb. 9, 2007).
[2] *Id*. at 2.
[3] *Id.*

IRP guideline, directing the utility to forecast demand and supply for flexible capacity resources and to evaluate such resources on a consistent and comparable basis with other resource options.[4]

2. Acknowledgment of PacifiCorp's 2019 IRP & 2020 AS-RFP

Coming out of the detailed portfolio modeling and stakeholder process in developing the 2019 IRP, PacifiCorp filed its 2020 All Source RFP ("2020AS RFP") with the Oregon PUC in February 2020. In July 2020, the Oregon PUC approved the 2020AS RFP, and PacifiCorp issued the 2020AS RFP to market. The initial shortlist included 5,652 MWs are new generation resources (represented by 3,173 MWs of solar generation and 2,479 MWs of wind generation) and an additional 1,330 MWs of new battery storage assets, which includes 1,130 MWs of solar collocated battery storage and 200 MWs of stand-alone battery storage. The company identified a final shortlist of winning bids in June 2021, comprising 1,792 MW of wind generation, 95 MW of standalone solar generation, 1,211 MW of solar generation paired with 497 MW of battery storage, and 200 MW of standalone battery storage; 590 MW of wind generation is being contracted as a build and transfer to PacifiCorp with the balance of the generation contracted through long-term power purchase agreements. In Order 21-437, the Commission acknowledged the 2020AS RFP final shortlist.

3. Development of PacifiCorp's 2021 IRP

PacifiCorp's 2021 IRP was developed through an extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public-input process began with a public-input meeting in January 2020. Over the subsequent year and a half, PacifiCorp met with stakeholders and hosted eighteen public-input meetings. Although PacifiCorp encountered multiple roadblocks during the portfolio modeling phase due to difficulties in developing portfolios using the new and robust tool PLEXOS, leading to many delays, we commend the PacifiCorp IRP team for their diligence in seeing the process through and coming up with portfolio results. Renewable Northwest submitted multiple feedback forms highlighting concerns related to capital costs and other assumptions that disadvantaged or incorrectly characterized storage and hybrid resources (discussed later in our comments) but overall we commend the IRP team for maintaining open dialogue and discussions throughout the IRP process.

[4] Oregon Public Utility Commission, Docket No. UM 1461, Order No. 12-013 at 16-18 (Jan. 19, 2012).

4. Resource Procurement & 2022 AS-RFP

At roughly the same time that PacifiCorp filed its 2021 IRP, the company also initiated the process for regulatory review of a proposed all-source RFP in 2022 (2022AS RFP). The 2021 IRP preferred portfolio includes 1,345 megawatts (MW) of new proxy renewable resources and 600 MW of collocated energy storage by the end of 2026. PacifiCorp has indicated that the 2022AS RFP will consider build-transfer, power purchase, and tolling agreement for generating and storage resources as well as professional services contracts for other resources, such as demand-side resource proposals. PacifiCorp has also stated that it will accept new and existing resources subject to certain conditions with terms between 5 and 30 years. Bids associated with these resources will be required to demonstrate their ability to be operational and deliver firm energy by December 31, 2026, or December 31, 2028 for long-lead time resources such as pumped storage hydro resources and nuclear. Renewable Northwest continues to be an active participant in the RFP docket at the Oregon PUC and had recently submitted comments[5] on the RFP Scoring, Modeling & Storage Methodology highlighting the intersection between this RFP and PacifiCorp's obligations under HB 2021 to reduce its greenhouse gas ("GHG") emissions significantly by 2030. More specifically, as the Commission concurrently reviews this IRP and the 2022AS RFP, we encourage the company and the Commission to view the IRP preferred portfolio as a reflection of pre-HB 2021 need and the RFP as an opportunity to achieve additional cost-effective emission reductions even as we work toward a clearer view of HB 2021 implementation.

III. COMMENTS

1. PacifiCorp's 2021 IRP Shows Continued Progress Toward A Low-Cost, Reliable and Clean Electric Grid.

PacifiCorp introduces its 2021 IRP by stating that "with accelerated coal retirements, no new fossil-fueled resources, continued growth in energy efficiency programs, and incremental renewable resources, the 2021 IRP preferred portfolio results in a greater reduction in greenhouse gas emissions relative to the 2019 IRP." It goes on to say that "[t]he 2021 IRP sets forth a path to build upon our significant progress toward the goals laid out in the 2017 and 2019 IRPs and identifies critical investments in expanded and modernized transmission, renewable energy, storage, demand response and advanced nuclear resources." From the lens of recently passed HB 2021 in Oregon, as well as the Clean Energy Transformation Act in Washington, it

[5] Renewable Northwest's Comments on UM-2193. Submitted on November 22, 2021. https://edocs.puc.state.or.us/efdocs/HAC/um2193hac165535.pdf

has become increasingly important to ensure that the glide path towards these states' statutory requirements leads to a reliable and cost-effective resource mix. In other words, taking significant actions toward compliance now will help ensure reliability and avoid unnecessary costs, while delaying compliance actions until closer to the years of these states' mandatory targets may be risky for the company's customers.

PacifiCorp's 2021 IRP continues on the path the company and stakeholders painstakingly established in the 2019 IRP in replacing thermal resources with renewables, energy storage, and hybrid resources with a specific eye to meeting reliability targets. The IRP's Preferred Portfolio shows the need to acquire almost 6 GW of solar, 3.6 GW of wind, 6 GW of storage and 4 GW of energy efficiency programs by 2040 as highlighted in the 2021 Roadmap. The roadmap also contains new transmission investments which may help the company to integrate large swathes of renewable energy projects including the 416-mile 500 kV Energy Gateway South from Wyoming to Utah and 290-mile 500 kV Boardman to Hemingway from Oregon to Idaho, developed in concert with Idaho Power.

While this overall trend continues to be positive, we offer the following specific feedback on some elements of PacifiCorp's analysis that could be improved to better reflect a least-cost, least-risk approach to the company's ongoing energy transition.:

a. *We recommend that PacifiCorp study the long-term costs and benefits of a more aggressive clean energy procurement compared to coal to gas conversion more carefully.*

While PacifiCorp's 2021 Roadmap and Preferred Portfolio portray that coal to gas conversion of Jim Bridger Units 1 & 2 is cost-effective in the near-term, that may not be the case in the long run. PacifiCorp estimates the capital cost to undertake the coal to gas conversion at around $24/kW excluding the variable cost of the fuel to generate electricity. The Preferred Portfolio shows that these converted units would then be retired 10 years post-conversion, i.e. in 2034. Additionally, PacifiCorp also mention that these units would be run as "peakers" i.e. they would deliver electricity only during times when the demand is high, particularly for a few hours in the summer and winter.

Renewable Northwest is concerned that PacifiCorp's proposal to convert the Bridger units to gas will delay the procurement of cost-effective clean, non-emitting capacity resources that can completely replace Jim Bridger Units 1 & 2, potentially foregoing the tax incentives available currently.[6] We recommend that the company undertake additional analysis to help the Commission and stakeholders fully understand the long-term costs and benefits of a more

[6] Mentioned on Pg 61, 2021 IRP.

aggressive procurement of capacity resources such as hybrid solar plus storage, standalone storage, and pumped-hydro to meet the company's needs during times when the Bridger peakers would operate to ensure that PacifiCorp customers are not left with uneconomic assets in the long run. In the portfolio modeling, without the gas conversion, the model optimizes the next-best selection and indicates that Jim Bridger Units 1 and 2 retire at the end of 2023 and an additional 700 MW of solar co-located with storage is added in 2024. Over 600 MW of non-emitting peakers displace a similar amount of solar co-located with storage over the 2031-2037 timeframe leading to lower overall emissions (1-2% lower) compared to the preferred portfolio (P02-MM-CETA). The higher NPVRR for this variant portfolio is partially caused by inflated capital, fixed operation & maintenance and demolition cost estimates inputted into the PLEXOS model as well as other related factors related to operational characteristics of storage resources discussed later. Another significant issue that has emerged across the US with events in Texas is the risk of relying on gas fuel supply during the winter peak events. PacifiCorp's PLEXOS modeling shows that Jim Bridger Unit 1 & 2, post-conversion, will be utilized as a peaking capacity resource during potential shortage events during winters creating a high-risk scenario wherein sudden spikes in fuel prices or scarcity may open PacifiCorp customers to extremely high fuel prices[7] or worse, unreliable service as was seen in Texas during February 2021. Relying on a peaking capacity resource which in itself is prone to unavailability creates unnecessary risks for PacifiCorp customers and we recommend a closer look by the Commission and PacifiCorp as to the viability of these coal to gas conversions instead of proven capacity resources like solar plus storage and pumped-hydro power plants. We recommend PacifiCorp model the high probability of gas price spikes during winter events[8] into their portfolio modeling and NPVRR calculations to evaluate the costs and reliability effects in the preferred portfolio.

b. *Integrated resource planning and resource procurement should adjust with changes in climate.*

The 2021 IRP mentions that "recent weather-based reliability events throughout the United States have underscored the need for utilities to consider the potential for increasingly extreme weather and the underlying reliability challenges that may be caused as part of its planning process." The Pacific Northwest has been a winter-peaking region historically but that is now changing with the weather-related impacts of climate change. Warmer weather events across the year are shifting the high loss-of-load-probability hours from the winter to the summer.[9] A

[7] Houston Ship Channel spot prices shot up to $400.000/MMBtu on Feb. 16 and remained sharply elevated for days as temperatures in the area plunged to the single digits.
[8] Winter supply disruptions from well freeze-offs can rival effects of summer storms. EIA. https://www.eia.gov/todayinenergy/detail.php?id=3390
[9] 2021 Northwest Power Plan - Draft.

similar effect can be observed in PacifiCorp's territory. Changes in weather necessitate procurement of resources that can operate efficiently during these weather conditions.

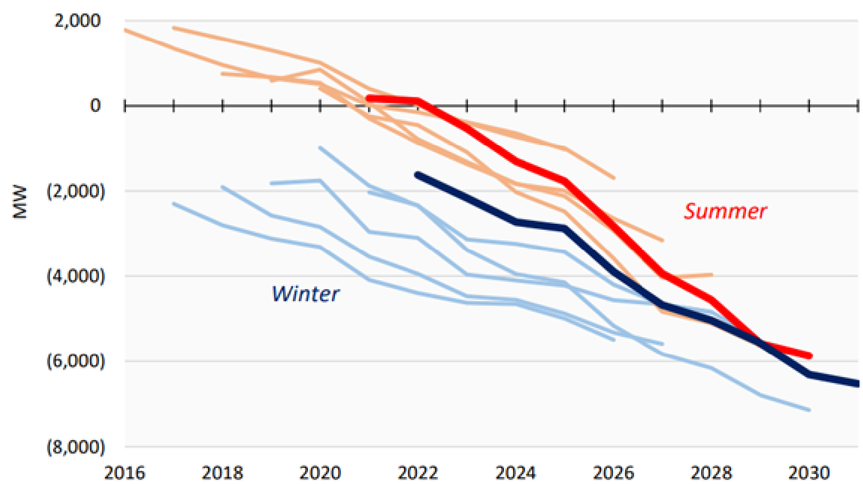

Figure 1. Summer and winter 1-hour peak surplus or deficit from the 2016 to 2021 Northwest Regional Forecasts.[10] The bold lines are 2021 projections.

With expected reductions in hydro generation[11] during the summer and increasing thermal forced outages, PacifiCorp would require large swathes of hybrid resources i.e. renewables paired with energy storage as well as standalone energy storage resources to provide clean and firm capacity across the year especially during the summer evenings. Weather-related thermal outages could be considered in future IRPs by developing a modeling framework which changes the output of thermal resources based on weather conditions. On the other hand, hybrid resources, specifically, solar plus storage or wind plus storage, can be implemented in various configurations based on the company's needs and are typically more reliable during summer peaking conditions. Broadly, they are categorized into AC-coupled and DC-coupled systems, with each having its own benefits. Recently, PacifiCorp's 2022AS RFP Team noted that they *would not* consider DC-coupled solar plus storage bids in this RFP because of difficulty in synergizing with California ISO and lack of sufficient metering infrastructure. This restriction, if not urgently addressed through engagement with CAISO and project developers, would create risks for PacifiCorp and its customers in its ability to procure the most cost-effective and clean capacity resources.

[10] Northwest Regional Forecast of Power Loads and Resources 2021 through 2031. Pacific Northwest Utilities Conference Committee (PNUCC).
[11] PacifiCorp currently owns 1,135 MW of hydroelectric generation capacity and purchases the output from 89 MW of other hydroelectric resources.

c. Cost projections for renewables and hybrids are declining rapidly.

PacifiCorp has reaped the benefits of low cost renewable energy resources and tax incentives associated with their procurement in the 2019 IRP and the 2020AS RFP. It is important to note that capital costs for photovoltaics, wind turbines, and battery storage resources continue to fall rapidly as shown in the recent NREL's Annual Technology Baseline 2021.[12] Another recent report[13], which details installed costs for PV systems as of the first quarter of 2021 states that costs continue to fall for residential, commercial rooftop, and utility-scale PV systems by 3%, 11%, and 12%, respectively, compared to last year, with a 19% reduction in module cost, causing overall costs to continue their decade-long decline. PacifiCorp's capital cost assumption coming out of a Burns & McDonnell report in the 2021 IRP for 1:1 solar plus storage hybrid resource is $2890/kW which is extremely high and does not square with recent RFPs or public cost data out of National Renewable Energy Laboratory (NREL). Additionally, adding demolition cost estimates of over $200/kW into portfolio modeling for projects without adding salvage value (value from recycling solar panels, battery packs and wind turbine materials) is speculative and artificially increases the capital costs of resources that are critical to achieve deep decarbonization.

With the likelihood that federal legislation will soon extend investment and production tax credits as well as incentivizing domestic procurement, PacifiCorp should capitalize on this opportunity to procure large amounts of resources to meet state policy targets in a rapid pace instead of implementing alternative approaches like coal-to-gas conversions which create a high risk low reward scenario for PacifiCorp and its customers. We strongly recommend that for the 2023 IRP cycle, PacifiCorp utilizes publicly available and comprehensive capital and O&M cost data in the inputs and assumptions for the portfolio modeling instead of relying on third-party vendor data which is calculated in a black-box setting. Portland General Electric, in their current IRP cycle, has committed to relying on public data sources[14]; we recommend PacifiCorp follow a similar practice.

---

[12] NREL Annual Technology Baseline 2021, *available at* https://atb.nrel.gov/. https://atb.nrel.gov/electricity/2021/data

[13] U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2021. NREL. https://www.nrel.gov/docs/fy22osti/80694.pdf

[14] Additional information is available in the slides and recording from PGE's November 18, 2021 IRP meeting, available at https://portlandgeneral.com/about/who-we-are/resource-planning/irp-public-meetings.

d. *Restricting market purchases to the same limit in all hours may artificially reduce the value of standalone and hybrid resources.*

PacifiCorp typically models spot market purchases or Front Office Transactions (FOTs) as proxy resources that are assumed to be firm to help the Company cover its short positions throughout the year. The Company mentions that "three FOT types were included for portfolio analysis in the 2021 IRP: an annual flat product, a HLH (Heavy Load Hours) July for summer, and a HLH December for winter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. The HLH transactions represent purchases received 16 hours per day, six days per week for July and December." IRP Table 7.1.1 states that PacifiCorp does not consider spot market purchases to be available across HLH in Mid-C during winter months and significantly reduces the market limit during those same hours in the summer. In response to Renewable Northwest's data request,[15] PacifiCorp stated that although increasing levels of solar generation coincide with HLH, this "does not necessarily translate into greater supply of HLH block products because the highest net demand hours are typically in the evening … which leads to increase in overnight market supply risk." While we agree with this premise, the resultant limitation across *all hours* is concerning especially in light of recent analysis[16] by other utilities in the region which shows that limiting market purchases can undervalue short and long-duration storage resources. This result occurs when a utility model assumes that the system might not have enough energy available to charge or "energy-fill" during the *lighter* HLH hours when there is little to no energy limitation for delivery or "energy-take" during *heavier* HLH and Super-Peak hours when the demand is highest. This is essentially causing the capacity contribution of short and long-duration storage to decrease artificially, leading to lower amounts selected to the preferred portfolio.

In future IRPs, PacifiCorp would be better suited to tackle this issue if the delineation between HLH and Super-peak hours is more defined because creating a restriction uniformly across all hours does not lead to a good modeling outcome. As the recent analysis underlying the 2021 Draft Northwest Power Plan has shown, regional procurement paired with significant hydro in the Pacific Northwest will likely create a scenario where Mid-C market prices remain low over the next decade significantly different from the projected prices shown in IRP Figure 8.6 with no tangible resource adequacy related shortfalls in the region.[17] Thus, market depth and resource

[15] Renewable Northwest's Data Request to PacifiCorp #5 (included in Attachment A)
[16] Review of Puget Sound Energy's ELCC Methodology. E3. 2021. https://www.pse.com/-/media/PDFs/001-Energy-Supply/003-Acquiring-Energy/PSE--ELCC-StudySept-202110072021FINAL.pdf?sc_lang=en&hash=AB72B5C439BDF50E3B931DCC4A11D40B
[17] RAAC-SAAC Steering Committee Meeting on Regional Resource Adeqaucy. https://nwcouncil.app.box.com/s/k12r8hry1ofogeqxgjw8spgnv2n55lvm

adequacy concerns should not create artificial situations wherein the resources needed to accelerate decarbonization are undervalued. Battery storage and pumped hydro resources are capable of providing short and long-duration energy storage capabilities which would be increasingly required in future IRPs.

2. PacifiCorp's PLEXOS Modeling & Analysis Is a Positive Step But More Work Is Needed in Future IRPs.

In the previous IRP, PacifiCorp's coal analysis and overall 2019 IRP development process demonstrated that many combinations of coal-unit retirements could bring significant economic benefits to its customers, even accounting for the costs associated with replacing those units' contributions to PacifiCorp's system. Renewable Northwest is encouraged that PacifiCorp has continued to improve on that method by employing a hybrid approach to coal retirement using PLEXOS' powerful modeling platform that has the ability to select retirement dates endogenously. We appreciate PacifiCorp's thoughtful and thorough approach to coal retirements, including its dynamic modeling to assess the economic impacts of coal retirements and new resource additions over time in determining a least-cost, least-risk portfolio.

In addition to the granular modeling, there is also a need for ensuring that climate-change adjusted weather and load forecasting methodologies are included in the baseline portfolio modeling. PacifiCorp states that "[t]he uncertainty in the company's load and resource balance is increasing as PacifiCorp's resource portfolio and customer demand evolve over time. While PacifiCorp took steps to better reflect the relationship between renewable resources and load in the 2021 IRP, uncertainty remains, particularly with regard to the frequency and characteristics of the relatively extreme conditions that are most likely to trigger reliability shortfalls." To reduce this uncertainty, we have extended our support and encouragement for the Northwest Power and Conservation Council to work in concert with utilities in the region to utilize weather, load, and hydro datasets to inform both utility-level and regional planning efforts. We recommend PacifiCorp work towards implementing these datasets in the PLEXOS modeling environment in the 2023 IRP process to ensure that the resource planning and procurement activities reflect the rapidly changing weather and loads in the region and reduce the uncertainties mentioned above.

With the emergence of the Western Resource Adequacy Program (WRAP) and concurrent dockets in Oregon like UM 2011, we recommend that PacifiCorp seriously consider moving away from a capacity factor approximation method to a more probabilistic effective load carrying capability ("ELCC") method to assign capacity contribution to resources; indeed, depending on how the Commission proceeds in UM 2011 this result may be required for the next IRP cycle. ELCCs can be calculated based on varying load and weather conditions and thus provide an additional layer of security in assigning capacity contribution values. In response to a data request[18] submitted by Renewable Northwest asking about the capacity factor approximation method, PacifiCorp responded that ELCCs are "computationally intensive and onerous" to calculate which although true does not relinquish PacifiCorp of its responsibilities to ensure the company pays for the value a resource provides. Since the CF approximation method uses a single stochastic study, it cannot capture the variability in weather and loads which are becoming increasingly prominent in the Pacific Northwest.

Additionally, PacifiCorp has been and continues to be an active participant in the program design and implementation of the WRAP. The Phase 2B detailed design mentions that the variable energy resources like wind and solar would be assigned an ELCC value based on their load-resource zone. In the future, to maintain uniformity between the obligations in WRAP and resource planning & procurement, it will be critical to align IRP practices with the WRAP so that PacifiCorp is not under or overvaluing resources. In response to another Renewable Northwest data request on their involvement with the WRAP, PacifiCorp mentioned that they objected to the request "on the grounds that it seeks information that is not relevant to the evaluation of the 2021 Integrated Resource Plan." Since the WRAP has the ability to reduce Planning Reserve Margins ("PRM") across its wide footprint by tapping into load and resource diversity, it is essential that the data submitted to the WRAP be also shared in the IRP context to ensure that there is a resonance in resource planning and regional efforts. For example, if the WRAP program operator determines that PacifiCorp would need to maintain a PRM of 7% in the summer, this would essentially lead to less peaking capacity requirements in the future which would in turn affect the retirement and conversion schedules of coal-fired power plants. Thus, the details of PacifiCorp's involvement in WRAP are essential in the IRP context and we recommend PacifiCorp provide more clarity as to the data submitted to the WRAP Program Operator in future 2021 IRP-related workshops.

3. PacifiCorp's Action Plan Reflects Broad Benefits Attributable to Non-Emitting Resources & Transmission Capacity But Overlooks Risks Associated with Thermal & Nuclear Resources.

Renewable Northwest supports the Preferred Portfolio (P02-MM-CETA) and the Action Plan associated with the 2021 IRP and commends PacifiCorp for implementing a tiered modeling framework in PLEXOS. The granularity and endogenous modeling capabilities afforded by this platform appear likely to create immense value for PacifiCorp and its customers. PacifiCorp's

[18] Renewable Northwest's Data Request to PacifiCorp #6 (included in Attachment A)

previous two IRPs showed the bulk of its coal-fired units retiring earlier than previously planned, but the 2021 modeling exercise has accelerated retirements of two units and delayed one. As noted above, the company proposes to convert Jim Bridger units 1 and 2 to gas-fired peaking plants in 2024. Additionally, PacifiCorp proposes to accelerate retirement of its 10-percent share of Colstrip units 3 and 4 in Montana to 2025, rather than 2027 as called for in the 2019 IRP. Naughton units 1 and 2 and Craig unit 1 are also slated for retirement in 2025, as called for in previous IRPs. The 2021 IRP also shows Hayden unit 2 retiring in 2027, rather than 2030, and the retirement of Craig unit 2 is pushed back to 2028 from 2026. In summation, the preferred portfolio reduces coal-fired generation capacity by 1,300 MW by the end of 2025, over 2,200 MW by 2030, and over 4,000 MW by 2040. We are also encouraged to see that over the 20-year planning horizon, the 2021 IRP preferred portfolio includes 3,628 MW of new wind and 5,628 MW of new solar co-located with storage and sizable demand-side management, key resources in our path towards complete decarbonization.

The 2021 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium *demonstration* project (emphasis added), which is supposed to come online by summer 2028 -- outside the action plan window. It is important to note that the project was fit into the portfolio modeling and the preferred portfolio in a brute-force manner essentially giving the PLEXOS model no choice but to select the resource in 2028. As PacifiCorp have stated, this nuclear project is a “demonstration” project which should be tested for its ability to provide cost-effective capacity to Oregon customers before being added as a supply-side resource in an IRP. Stakeholders were not provided information about this demonstration project until late in the IRP-development process, nor were details on licensing, siting and permitting discussed publicly until recently. Relying on a demonstration project in portfolio modeling creates an inherent risk in delaying proven technologies that can provide clean, renewable and non-emitting capacity like solar plus storage and emerging technologies that are proven elsewhere like Offshore Wind. In fact, one of the preferred portfolio variants, P-02e-No NUC -- which excludes this project -- shows that procuring hybrid solar plus storage and standalone storage resources provides sufficient reliability, albeit with slightly higher costs but with low to zero risk of projects[19] not coming online which is one of the biggest risks in relying on a nuclear power plant in the current climate.

As mentioned above, PacifiCorp’s territory is more suited towards evaluating the costs and benefits of deploying technologies like offshore wind. As Staff stated in their opening comments, “recent studies have found that OSW may provide a significant amount of winter-peaking, high-capacity factor renewable energy to customers, without the need for major transmission

[19] Without the Natrium demonstration project, 348 MW of solar co-located with storage is added to the portfolio in 2026 and an additional 240 MW is added in 2030.

upgrades."[20] The 2.6 GW OSW potential in Oregon without need for major transmission overhaul could be a valuable opportunity for PacifiCorp to tap into a proven technology with attractive tax incentives that can help ameliorate capacity needs that PacifiCorp sees in its portfolio modeling. Thus, we support Staff in their recommendation to ensure that OSW is studied and modeled in PLEXOS by developing an option to add this resource starting in 2028 or 2030 as an alternative to the Natrium nuclear power plant. Renewable Northwest would be happy to discuss this going forward and help the company obtain generation shapes and other data from research being conducted in national labs across the country.

IV. CONCLUSION

Renewable Northwest again thanks the Commission for this opportunity to comment on PacifiCorp's 2021 IRP. We reiterate our appreciation to PacifiCorp for its robust stakeholder process and our support for this important step in the company's transition from a carbon-intensive thermal portfolio to a modern system powered by renewables and balanced with other non-emitting resources. We look forward to continued collaboration with the Commission, PacifiCorp, stakeholders, and Commission Staff throughout this IRP proceeding.

Respectfully submitted this 3rd day of December, 2021,

/s/ Sashwat Roy
Technology & Policy Analyst
Renewable Northwest
421 SW Sixth Ave. #1400
Portland, OR 97204
(503) 223-4544

/s/ Max Greene
Regulatory & Policy Director
Renewable Northwest
421 SW Sixth Ave. #1400
Portland, OR 97204
(503) 223-4544

[20] PNNL. Exploring the Grid Value Potential of Offshore Wind Energy in Oregon. May 2020

Attachment A

PacifiCorp Response to Renewable Northwest Data Request 5 & 6 in LC 77

RNW Data Request 5

Reliability and Resource Adequacy
The 2021 IRP Front Office Transaction (wholesale market) limits are 1,000 MW in the winter, and 500 MW in the summer, reduced from 1,425 MW in the 2021 IRP. Please provide an explanation as to why Mid-C capacity was restricted in both Flat Annual and Heavy Load hours.

Response to RNW Data Request 5

Increasing levels of solar generation across the western interconnect have resulted in greater supply during daylight hours, most of which coincide with heavy load hours (HLH). This does not necessarily translate to greater supply for HLH block products, because the highest net demand hours (load net of renewable output) are often in the evening, which is still part of HLH. However, because net demand is becoming higher overnight relative to during the day (as a result of solar generation), overnight market supply risk is increasing. In light of these trends, the Company’s analysis restricts market purchases to the same limit in all hours for planning purposes.

RNW Data Request 6

Reliability and Resource Adequacy
Regarding the Capacity Factor Approximation Method (CF Method) that the Company utilizes to calculate capacity contribution of supply-side resources:

(a) How is the CF Method different from Marginal ELCC employed by other IOUs in the region?

(b) The IRP mentions that "for capacity expansion optimization modeling, market purchases contribute capacity toward meeting the 2021 IRP's capacity reserve margin and supply energy to meet system needs." Are market purchases assigned a capacity factor? If so, how are the capacity factors or availability defined in Plexos' ST and MT model for all three FOT types mentioned in the IRP?

Response to RNW Data Request 6

(a) Please refer to PacifiCorp's 2021 Integrated Resource Plan (IRP), Volume II, Appendix K (Capacity Contribution). The more computationally intensive reliability-based method is the effective load carrying capability (ELCC) metric. The ELCC of a generator is defined as the amount by which the system's loads can increase (when the generator is added to the system) while maintaining the same system reliability (as measured by the loss of load probability (LOLP) and loss of load events (LOLE)). The ELCC method thus requires two studies: a baseline portfolio and load, and a portfolio with the resource being evaluated added along with a "to be determined" amount of load added. Each study would involve a large number of iterations to capture stochastic variables (e.g. load, hydro conditions, and thermal outages in the 2021 IRP) so it represents a significant amount of model run time. Multiple studies may also be required to pinpoint the load carrying capability. While the baseline study is the same in each case, the modified portfolio and load study will be different for each resource that is to be evaluated. Because of the model run time, need to re-evaluate load inputs, and resource specificity of the results, the ELCC method is quite onerous to complete. As discussed in a 2012 report produced by the National Renewable Energy Laboratory (NREL Report)[1], the capacity factor approximation method (CF Method) was found to be the most dependable technique in deriving capacity contribution values that approximate those developed using the ELCC Method. The CF Method uses a single stochastic study, equivalent to the baseline portfolio and load used for the ELCC method above. That study identifies the periods in which there is a risk of LOLE, and any resource profile can be compared against those events to identify a capacity contribution value.

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report) at: www.nrel.gov/docs/fy12osti/54704.pdf

(b) No capacity factor (CF) is assigned to market purchases as the PLEXOS model determines the dispatch levels for market purchases up to specified limits, resulting in a CF of up to 100 percent in any hour that market purchases are called upon. Because market purchases have the option to dispatch at up to 100 percent, they also provide a capacity contribution of 100 percent, but only to the extent that they are available. The Company would note that market purchase limits were reduced significantly for the 2021 IRP in light of regional reliability concerns. For details, please refer to Table 5.8 (Maximum Available Front Office Transactions by Market Hub) on page 114 of Volume I of the 2021 IRP.